U.S. Department of Transportation
United States Coast Guard

Commander
Eighth Coast Guard District
Hale Boggs Federal Bldg.

501 Magazine Street
New Orleans, LA 70130-3396
Staff Symbol: (md)
Phone: (504) 589-3647

16451
1 June 1998

From: Commander, Eighth Coast Guard District
To: Distribution

Subj: ALTERNATIVE PIPELINE TESTING

1. Enclosures (1) and (2) are forwarded for your information and use.

2. These documents open the door for the COTPs to accept an alternative inspection protocol for facility piping. This testing protocol could yield equivalent or superior results with a reduced potential for pollution.

Guy A. Tetreau
G. A. TETREAU
By direction

Encl: (1) COMDT (G-MOC-3) ltr 16700 of 21 May 1998
(2) MSO Houston-Galveston ltr 16451 of 1 May 1998

Dist: All Eight District MSOs, MSU and MSDs

U.S. Department of Transportation
United States Coast Guard

Commandant
United States Coast Guard

2100 Second Street, S.W.
Washington, DC 20593-0001
Staff Symbol: (G-MOC-3)
Phone: (202)-267-0499
FAX: (202)-267-0506

16700
MAY 21 1998

From: Commandant (G-MOC-3)
To: Commanding Officer, Marine Safety Office Houston-Galveston
Via: Commander, Eighth Coast Guard District (m) 5/21/98

Subj: SHELL DEER PARK REFINING COMPANY; ALTERNATIVE PIPELINE TESTING REQUEST

Ref: (a) MSO Houston-Galveston ltr 16451 of 1 May 1998

1. In response to reference (a), this office has reviewed the request from Shell Deer Park Refining Company for approval to utilize a marine transfer piping inspection program, based on American Petroleum Institute's Piping Inspection Code (API-570), in lieu of conducting annual static liquid pressure tests required by 33 CFR 156.170 and 33 CFR 127.1407(a)(4).

2. Based upon the justification and information provided to support the proposal, Shell Deer Park's request is approved in concept. The API-570 standard is a suitable guideline from which a facility specific detailed inspection program may be established, for your approval in accordance with 33 CFR 156.107. Alternatives granted under this authority are subject to COTP withdrawal, if at any time it is determined that the safety and pollution prevention requirements are not adequately complied with. The following recommendations are provided for approving and coordinating the implementation of the facility's program:

a. Visual inspections of the complete transfer piping system (refer to recommended maximum inspection intervals; API-570 Section 4.2, Table 1) shall be conducted and documented annually. Shell Deer Park Refining Company's letter of 20 May 1998 amends the subject request to reflect this requirement.

b. An API Certified Pipeline Inspector shall conduct inspections and testing; the results shall be reviewed and approved by a Piping Engineer.

c. A revolving in-service inspection program, whereby a percentage of the facility's lines are tested annually, must address the complete marine transfer piping system during a maximum five year interval

d. Test results and visual examination reports shall be maintained at the facility for the duration of the pipeline service life, and shall be readily available for examination by the COTP. Approved alternative pipeline testing procedures shall be maintained with test results required by 33 CFR 154.740(c).

Enclosure (/)

3. A Navigation and Vessel Inspection Circular is currently being developed to provide uniform guidance for the approval of API-570 based inspection programs, as alternative compliance to the pipeline testing requirements. Should your staff have any additional questions or comments in the interim, or require assistance with the review/approval of Shell Deer Park Refining Company's inspection program, please contact this office at the above telephone number.

Russell C Proctor
R. C. PROCTOR
By direction

md
16451
11 May 1998

FIRST ENDORSEMENT on MSO Houston-Galveston ltr 16451 of 1 May 1998

From: Commander, Eighth Coast Guard District
To: Commandant (G-MOC-3)

Subj: SHELL DEER PARK REFINING COMPANY PIPE SYSTEM TESTING

1. Forwarded, recommending approval. This examination protocol appears to be equivalent or superior to the required annual pressure test and offers a reduced risk of pollution resulting from the piping system evaluation.

2. Due to Shell's May 21st deadline, it is requested that this request be given immediate attention.

Guy A. Tetreau
G. A. TETREAU
By direction

Copy: MSO Houston-Galveston

Enclosure (2)

U.S. Department of Transportation

United States Coast Guard

Captain of the Port
U. S. Coast Guard Marine Safety Office Houston-Galveston

P.O. Box 446
Galena Park, TX 77547-0446
Phone: (713)671-5100

16451

MAY 1 1998

From: Commanding Officer, U. S. Coast Guard Marine Safety Office Houston-Galveston
To: Commandant (G-MOC-3)
Via: Commander, Eighth Coast Guard District (m)

Subj: SHELL DEER PARK REFINING COMPANY PIPE SYSTEM TESTING

Ref: (a) Piping Inspection Code ANSI/API 570-1993

1. Enclosed is a letter from Shell Deer Park dated April 21, 1998 that is being forwarded for your consideration. Mr. Brett Woltjen, Shell Deer Park Refining Company's logistics manager, is requesting an alternative procedure for testing their marine transfer systems in accordance with Titles 33 CFR 156.170 and 33 CFR 127.1407.

2. I have reviewed Shell's proposal for non-destructive testing of all piping regulated under Titles 33 CFR 156.170 and 33 CFR 127.1407 and the API 570 Piping Inspection Code, reference (a), published by the American Petroleum Institute. It is my understanding that Shell Refining Company intends to implement this on a nationwide basis if it is approved by the Coast Guard, and a large number of local companies are expected to request a similar alternative if Shell's request is approved.

3. Due to the scope and national implications of this request, I have given it extra consideration. The inspection and repair procedures outlined in API 570 are extensive and require very accurate long term record keeping. For example, at the five year metal thickness gauging exam, 50% of the predetermined test points are gauged, thus the entire piping system will be evaluated over the course of a decade. If test results are either improperly recorded or records are carelessly maintained, piping systems could be overlooked.

4. The API 570 code for the inspection, repair, alteration, and rerating of in-service piping systems appears to be sound engineering and logically formatted. Due to the preventive nature of the code, the long term overall maintenance of the piping systems should be improved.

5. Enclosures (2) and (3) provide a history of a similar approach requested by Exxon Company U.S.A. that was considerably smaller in scope and was accepted as an alternative procedure for testing their piping systems on one dock. The system has proven effective for Exxon U.S.A. since it was put into use in April of 1992.

16451
MAY 1 1998

Subj: SHELL DEER PARK REFINING COMPANY PIPE SYSTEM TESTING

6. Again, due to the potential nationwide impact of approving this request, I am forwarding it to you for final disposition along with my recommendation that Shell Deer Park Refining Company be granted an alternative for non-destructive pipe testing done in accordance with API 570. This alternative should be reviewed annually, coincident with the facility inspection, and subject to appeal if shown to be not as effective as static liquid testing.

K. J. ELDRIDGE

Encl: (1) Shell Deer Park ltr dtd 21 Apr 98
(2) COMDT (G-MEP) ltr dtd 10 Jul 92
(3) MSO Houston-Galveston ltr dtd 21 Apr 92

Copy: (1) Shell Deer Park Refining Company (without enclosures)

Shell Deer Park Refining Company
A Division of Shell Oil Company

P. O. Box 100
Deer Park, TX 77536

April 21, 1998

USCG MSO HOUSTON
APR 21 1998
RECEIVED

Captain Kevin J. Eldridge, U.S. Coast Guard
Captain of the Port
U.S. Coast Guard Marine Safety Office Houston - Galveston
P. O. Box 446
Galena Park, TX 77547 - 0446

Subject: Alternative Compliance with Title 33 CFR 156.170 / 127.407

References:
(1) Title 33 CFR 156 Section 170 "Equipment Tests and Inspections"
(2) Title 33 CFR 127 Section 407 "Testing"
(3) CMDT (G-MEP-1) letter of August 3, 1994 on "Facility Pipeline Testing"
(4) Title 33 CFR 156 Section 107 "Alternatives"
(5) Title 33 CFR 127 Section 017 "Alternatives"
(6) API 570 "Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems"

Dear Captain Eldridge:

Shell Deer Park Refining Company (SDPRC) hereby requests approval to utilize an API 570 based marine transfer piping inspection program in lieu of annual pressure testing required by 33 CFR 156 and 127. Justification and information to support this alternative are provided in accordance with the Commandant's Policy on Facility Pipeline Testing. SDPRC's marine transfer piping inspection program was established in 1992 and is consistent with API 570 - the industry standard for inspection of refining and petrochemical plant piping systems. This program affords an equivalent level of safety - while providing an even more effective means of managing pipeline risks. This request is aligned with the Coast Guard's objectives of regulatory reform, partnering with industry, risk management, and streamlined inspection. Coast Guard approval is needed within 30 days of receipt to address the June 1998 scheduled pressure test requirements.

Located on the Houston Ship Channel in Deer Park, Texas, 20 miles east of downtown Houston, SDPRC is Shell Oil Products Company's second largest refinery and Shell Chemical Company's largest chemical plant. The Refinery and Chemical Plant make about one-fourth of all Shell products. SDPRC ranks as the 25th largest port in the U.S. by volume. SDPRC employs a workforce of about 2200 employees and averages 1000 contractors on a daily basis. Property taxes are approximately $40 million annually.

ENCLOSURE 1

SDPRC TRANSFER PIPING SYSTEMS DATA

In 1997 SDPRC docks handled 3244 transfers and over 125 million barrels of oil, hazardous materials and liquefied hazardous gases. SDPRC operates five docks with over 80 **transfer piping systems required to be pressure tested annually.** Tests are performed at 1 1/2 times the maximum allowable working pressure of each pipeline and include all piping from the dock loading manifold / arm to the first block valve inside the Spill Prevention Control and Countermeasure area. Operating history and test results have shown no breaches in the pressure retaining boundary of the piping in areas that could cause water pollution risks. SDPRC spends about **$30,000 per year to pressure test transfer piping** in accordance with 33 CFR 156 and 33 CFR 127. Appendix 1 summarizes piping systems data: age, dimensions, commodities transferred, access, relief valve settings and maintenance, date of last static liquid test, MAWP, and system operating pressures. The last Coast Guard facility inspection at SDPRC was in November 1997.

API-570 / BACKGROUND

API 570 classifies piping containing hazardous materials that would result in an immediate health, safety, or environmental emergency if a leak were to occur, **as high risk or Class 1.** Examples of these include hydrogen sulfide, hydrofluoric acid, services that may auto refrigerate upon leaking and lead to brittle fracture of the pipe, and piping over or adjacent to water. The petrochemical industry practice most widely used to provide long term reliability and prevent leaks on all piping systems is API 570. API 570 is also published by the American National Standards Institute as ANSI/API 570.

The most likely deterioration mode of the SDPRC piping subject to annual pressure test requirements is from external corrosion due to paint and coating failures and other influences that can accelerate corrosion on the exterior surface of the pipe. External issues are best identified by a thorough visual and thickness monitoring inspection in accordance with API 570. Two SDPRC marine transfer piping systems (crude ECH and ballast) are subject to internal corrosion as the predominant deterioration mechanism. Internal issues are best identified by thickness monitoring inspection in accordance with API 570. All piping over and adjacent to the water is located in piperacks above roadways and dock facilities; the systems are well protected from inadvertent vehicular or personnel damage (Appendix 2 shows examples of piping locations).

Pressure testing will typically not uncover deterioration in pipe until it is very severe because there is very little stress applied relative to the yield stress of the material. Pressure testing is only a proof test for leaks and very near penetration corrosion at a point in time. It only checks the validity of the pipe at the time of testing, it can not predict deterioration mechanisms or rates of deterioration. An API 570 inspection is a preventive maintenance approach used to identify and correct deterioration mechanisms before they can cause leaks.

Pressure testing is the most effective form of piping integrity evaluation and inspection when piping is constructed or when it is repaired or altered. It is an excellent tool to determine if there is an inherent defect in the material. This is a requirement of API 570 and has always been a requirement for all piping systems at SDPRC.

SDPRC INSPECTION PROGRAM (see Appendices 3 and 4)

In 1992 the SDPRC Pressure Equipment Group inspected all marine transfer piping, approximately 190,000 linear feet, in accordance with "Shell Manufacturing Piping Inspection Requirements" which was the base document for development of API 570. This included extensive visual inspections and measurements at approximately 32,000 thickness monitoring locations (TML's). No significant piping degradation issues or reliability concerns were identified and it was concluded that future operations and pressure tests would present minimal risk in creating breaches in the pressure retaining boundary of the piping. A second inspection of this piping in accordance with API 570 is now in progress and scheduled for completion by the end of April. Upon 75% completion, no leaks or significant deterioration issues had been found. Appendix 5 presents a sample of results from these inspections.

SDPRC proposes that all transfer piping regulated under 33 CFR 156.170 and 33 CFR 127.407 be inspected in accordance with Appendix 3 and the latest edition of API 570 in lieu of annual pressure testing. All piping that could cause pollution risks to the water would be classified per API 570 as Class 1 piping, which is the highest risk classification. Visual and thickness monitoring inspections would be required at intervals not exceeding 5 years (Appendix 3). The inspection would also include the vapor control system (VCS) piping - which is not included in the annual test requirements. It is estimated that these inspections would cost approximately $5,000 per year - a cost savings of about $25,000 per year when compared to annual pressure testing costs. Most importantly, it would eliminate the safety and pollution hazards associated with pressure testing the lines. Due to the inability to decontaminate the piping being tested, a pipe that fails a pressure test could cause contaminated water or product to enter the Houston Ship Channel.

CONTACTS

We appreciate your prompt consideration of this request. Should you need additional information, please contact Jimmy Brown (Senior Engineer, SDPRC Pressure Equipment Inspection) at (713) 246-7836, Dan Lozano (Dock Operations Foreman, SDPRC Logistics) at (713) 246-7595, or Bob Conn (Technical Superintendent, Equilon Marine) at (713)241-5644.

Very truly yours,

Brett D. Woltjen

Brett Woltjen
Manager Logistics
Shell Deer Park Refining Company

cc: Captain John Schrinner, U.S. Coast Guard
Commandant (G-MOC)
2100 Second St. S.W.
Washington, DC 20593-0001

U.S. Department of Transportation
United States Coast Guard

Commandant
U.S. Coast Guard

2100 Second Street S.W.
Washington, DC 20593-0001
Staff Symbol: (G-MEP-1
Phone: (202) 267-6714

16450
10 JUL 1992

Mr. Mike Norcross
Dockmaster
EXXON Company, U.S.A.
P. O. Box 3950
Baytown, TX 77522-3950

Dear Mr. Norcross:

This is in response to your letter of April 21, 1992, to Commanding Officer, Marine Safety Office Houston, in which you request approval of alternative(s) to the pipeline testing requirement outlined in Title 33 CFR Part 156.170.

Your request is approved as recommended by Marine Safety Office Houston. Testing of the #1 Dock piperack shall be performed in accordance with API 570. Testing is to be done annually for three years with results reported to the Marine Safety Office Houston. Any temporary repairs made to the piping system shall also be reported to that office.

This alternative will be reviewed annually by Marine Safety Office Houston and is subject to repeal if shown not to be as effective as static liquid testing.

If you have any questions or need further assistance, please feel free to contact me at (202) 267-6714.

Sincerely,

L. J. BEACH
Commander, U. S. Coast Guard
Chief, Prevention, Enforcement, and Standards Branch
By direction of the Commandant

Copy: Commander, Eighth Coast Guard District (m)
Commanding Officer, Marine Safety Officer, Houston

ENCLOSURE (2)

Appendix 5
Select Results from 1992 and 1998 Inspections

Line Identification Number	Service	Size	Summary of 1992 Visual Inspection Results	Summary of 1998 Visual Inspection Results	1992 Average Thickness	1998 Average Thickness	Corrosion Rate (Inches/year)	Renewal Thickness* (Inches)	Remaining Corrosion Allowance (Inches)
P603107 Circuit A	#5 Solvent	8"	Moderate paint failure noted at several locations. Pitted areas at heat affected zones of welds at circuits A03 and A04 were gauged and found to be ok. Overall pipe is in good condition	Exterior paint is in good condition only minor paint failures noted. All branch connections looked good with no defects noted. In summary the entire piping system is in good condition.	0.332"	0.332"	0	0.15"	0.182"
P603111 Circuit B	#1Solvent	8"	Severe paint failure noted at several locations, surface rust is present. Minor corrosion occurring at HAZ of some welds. Overall piping is in good condition.	Exterior paint system is in good condition, only minor isolated failures noted. No defects noted. In summary the entire line is in good condition.	0.304"	0.303"	<0.001	0.15"	0.153"
P603115 Circuit B	Toluene	8"	Paint failures were noted in circuit C. One area of minor external corrosion was noted in circuits C-06 and C-07. Overall piping is in good condition.	Exterior paint system is in good condition, only minor isolated failures noted. No defects noted. In summary the entire line is in good condition.	0.345"	0.340"	0.001	0.15"	0.190"
P603143 Circuit C	Heavy Cat Cracked Gas Oil	8"	Insulated Piping. Areas selected for CUI inspection revealed no corrosion. Some insulation and jacket damage noted, but the overall condition of the insulation is good.	Insulation in generally good condition with only minor failures noted. Exterior paint system on the portion of the line that is not insulated is in good condition with only minor paint failures noted. In summary the entire line is in good condition.	0.313"	0.307"	0.001	0.15"	0.157"
P603151 Circuit E	#2 Crude Line	12"	A portion of the pipe is insulated. CUI inspection using radiography showed no corrosion. The painted portion of the pipe is in good condition with no evidence of corrosion or surface rust. One areas of external pitting was measured and is ok.	Exterior paint and insulation system is in good condition with only minor failures noted during the inspection. No defects were noted. Overall condition of the piping system is good.	0.312"	0.308"	<0.001	0.188"	0.120"

* Per Appendix 3

Appendix 4
Determination of the Number of TML's

This appendix is a guide for establishing the minimum number of thickness monitoring locations (TML's) for each Class 1 piping system. The method takes into account the length of the line, number of fittings[1], and the average corrosion rate for the piping system. This method is taken from the Shell Oil Company document "Best Practice and Guideline for In-Service Piping Inspection" Revision 3, March 1998.

[1] Fittings are defined as elbows, tees, valves, bleeders, vents or any protrusions from the pipe and flanges.

The general formula is:

Number of TML's = (L + F)x(C)

The factors for this equation are defined in the following table.

Factor	Value
L = Length Factor	
0 - 30 ft	0.5
31-100 ft	1.0
101 - 200 ft	1.5
201 - 500 ft	2.0
501 - 1000 ft	2.5
> 1000 ft	3.0
F = Fitting Factor	0.75xN
C = Corrosion Rate Factor	
CR < 0.002 in./yr.	0.5
CR= 0.002 - 0.010 in./yr.	1.0
CR > 0.010 in./yr.	2.0

N = Number of fittings.
CR = Average corrosion rate for the piping system.

Example:
A class 1 line with 600 linear feet of piping contains 12 elbows, 2 tees, 2 bleeder valves, and 1 vent valve. The average corrosion rate for the system is 0.001 inches/year.

Utilizing the above table and formula, the number of TML's would be calculated as follows: L = 2.5,N = 17, F = 0.75 x 17 = 12.75, C = 0.5

Number of TML's = (L + F)x(C) = (2.5 + 12.75)x(0.5) = 16 be done in accordance with the Shell Oil Company document "The Non Destructive Evaluation Technical Direction Team - Procedure for Radiographic Profile Thickness Measurement". All data gatherers will be trained and tested in accordance with the appropriate procedure being used to measure thickness.

Corrosion Under Insulation (CUI)

Insulated piping can be subject to external corrosion due to breaches in protective covering of the insulation that can allow moisture to enter and set up corrosion cells. Insulated piping makes up about 5% of the piping covered by pressure test requirements at SDPRC. Insulated piping systems that operate below 250 F or steam traced piping systems that experience tracing leaks are most susceptible to CUI. The external inspection of the insulated piping system will include a review of the integrity of the insulation system for conditions that could lead to CUI or signs of ongoing CUI. Thickness measurements at TML's can be obtained utilizing the profile radiography technique mentioned above. All issues found on this inspection will be documented in the inspection narrative report and issues that need corrective action will be mitigated. The CUI inspection interval will be set based on the results of this inspection. A shorter interval will be used if a high-risk situation is identified. All CUI inspections will be performed by API 570 inspectors and thickness data will be obtained by trained and certified NDE technicians.

Renewal Thickness

Each TML in the record system will have a renewal thickness as shown in the table below. Renewal thicknesses are based on internal pressure and structural loading expected in manufacturing facilities. This thickness will be used in calculating the expected remaining life and the interval until the next TML inspection. No piping component should continue in operation with remaining thickness below this renewal thickness unless an engineering review is conducted and documented that shows the component fit for continued service.

Renewal Thickness for Pipe[1]

Pipe Size	Renewal Thickness
3" or less	0.100"
4" and 5"	0.110"
6" thru 10"	0.150"
12" thru 24"	0.188"

[1] Excerpt from Shell Oil Company document "Best Practice and Guideline for In-service Piping Inspection", Revision 3, March 1998.

Appendix 3
Inspection Program

Abbreviations

TML - Thickness Monitoring Location
CUI - Corrosion Under Insulation
NDE - Non Destructive Evaluation

Inspection Intervals

Maximum interval between Class 1 piping inspections (based on API 570):

Type of Inspection	Maximum Interval
Visual	5 years
TML	5 years
CUI	5 years

Visual Inspections

An external visual inspection is performed to determine the condition of the outside of the piping. The primary focus is on the condition of the paint and coating systems and any associated hardware that could contribute to the deterioration of the external surface of the pipe. If corrosion or any other form of deterioration is noted, it will be further evaluated for necessary corrective action. All issues found on this inspection will be documented in the inspection narrative report and issues that need corrective action will be mitigated. **The visual inspection interval will be set basis the results of this inspection.** In some cases the maximum interval may not be used if a high-risk situation is identified indicating the need for a shorter inspection interval. All visual inspections are performed by inspectors certified in accordance with Appendix B of API 570.

TML Monitoring

The pipe wall thickness in each piping system will be monitored by taking thickness measurements at designated TML's. The number of TML's will be established using the method shown in Appendix 4. TML's should be distributed appropriately throughout the length of the pipe on both fitting and pipe components. **Each thickness measurement inspection should obtain thickness readings on at least 50% of the TML's on each piping system.** These TML's should be rotated each inspection so **all TML's are monitored over time.** Thickness measurements will be taken using ultrasonic and profile radiography techniques.

All thickness data will be measured by trained and certified Non Destructive Evaluation (NDE) technicians and evaluated by the API 570 inspector. Ultrasonic thickness measurements will be done in accordance with the Shell Oil Company document "The Non Destructive Evaluation Technical Direction Team - Procedure for Ultrasonic Thickness Gauging of Pressure Equipment". Profile radiography will

APPENDIX1 (CONTINUED)

SDPRC MARINE TRANSFER PIPING SYSTEM+A109S DATA

SYSTEM / COMMODITIES	SYSTEM TEST ID	DOCK LOCATION (S)	SIZE ID (INCHES) (4)	MAWP (PSI) (5)	OPERATING PRESSURE (PSI) (6)	TPRV (PSI) (7)	ACCESS
#1 LUBE	P603131	WEST, CENTER, EAST	10	200	45	(8)	ELEV
#2 LUBE	P603132	WEST, CENTER, EAST	10	200	45	(8)	ELEV
LUBE VENT	P603123	WEST, EAST,	2, 4	200	180	(8)	ELEV
LHG	P603145	WEST, EAST,	12	200	75	275	ELEV/INSUL
LHG FLARE LINE	P603146	WEST, EAST,	4, 6	200	60	(8)	ELEV
TOLUENE	P603115	WEST, CENTER, EAST	10	200	60	150	ELEV
#3 SOL SOL140	P603109	WEST, CENTER, EAST	6, 8	200	35	275	ELEV
FURNACE OIL	P603153	WEST, CENTER, EAST, CRUDE	12, 16	200	60	275	ELEV
DMK D345	P603164	CENTER, EAST	3, 6	250	45	150	ELEV
OPII PITCH	P603137	EAST, BARGE	6, 8	250	70	150	ELEV/INSUL
HCCGO	P603143	WEST, CENTER, EAST, BARGE	6, 8	250	45	(8)	ELEV/INSUL
#1 GASOLINE	P603166	WEST, CENTER, EAST	12, 18	250	75	275	ELEV
#2 GASOLINE	P603128	WEST, CENTER, EAST	10, 12, 16	250	75	275	ELEV
#2 SOL SOL340	P603110	WEST, CENTER, EAST	6, 8	250	35	275	ELEV
#6 FUEL OIL	P603157	WEST, CENTER, EAST, CRUDE	12, 16	250	45	275	ELEV/INSUL
BUNKER C	P603155	WEST, CENTER, EAST	16	250	45	275	ELEV/INSUL
ALGERIAN CONDENSATE	P603130	WEST, CENTER, EAST	18	250	75	275	ELEV
#3 CRUDE	P603167	WEST, EAST, CRUDE	24	250	110	250	ELEV
#4 CRUDE	P603114	CRUDE	24	250	110	275	ELEV
#1 MARINE LOADING ARM FURN OIL	B070552	CRUDE	12	250	40	(8)	ELEV
#2 MARINE LOADING ARM FUEL OIL	B070553	CRUDE	12	250	25	(8)	ELEV
#3 MARINE LOADING ARM CRUDE	B070554	CRUDE	16	250	110	(8)	ELEV
#4 MARINE LOADING ARM CRUDE	B070555	CRUDE	16	250	110	(8)	ELEV
#5 MARINE LOADING ARM CRUDE	B070556	CRUDE	16	250	110	(8)	ELEV
OILY WATER SUMP	P603170	WEST	2, 4	285	90	(8)	ELEV
OILY WATER SUMP	P603101	CENTER	2, 4	285	90	(8)	ELEV
OILY WATER SUMP	P603174	EAST	2, 4	285	90	(8)	ELEV
OILY WATER SUMP	B070550	BARGE	3	285	90	(8)	ELEV
OILY WATER SUMP	P603178	CRUDE	6	285	90	250	ELEV

NOTES:

(1) ALL PIPING EXCEPT MTBE AND VCS WAS INSTALLED IN 1979. MTBE WAS INSTALLED IN 1992 AND VCS WAS INSTALLED IN 1997.

(2) THE ONLY OPERATING RELIEF VALVES ARE ON THE VAPOR CONTROL SYSTEM WHICH ARE SET AT 1.6 PSI.

(3) LAST FACILITY INSPECTION WAS ON 11/97. LAST PIPELINE PRESSURE TESTING WAS ON 6/97.

(4) 1.5, 2, 3, 4, 6, 8, 10 & 12 ID ARE SCH. 40. 14, 16, & 18 ARE SCH. 30. 24 IS SCH. 20. REF. SHELL ENG. GUIDE & GENERAL SPECIFICATIONS.

(5) MAWP IS BASED ON PUMP DEAD HEAD PRESSURE.

(6) SYSTEM OPERATING PRESSURE BASED ON EXPERIENCE.

(7) ROUTINE MAINTENANCE SCHEDULE GOVERNED BY API 510.

(8) NO TPRV INSTALLED AS SYSTEM IS EMPTY, IN CIRCULATION OR LINED UP TO TANK WHEN NOT IN USE.

APPENDIX 1

SDPRC MARINE TRANSFER PIPING SYSTEM DATA

SYSTEM / COMMODITIES	SYSTEM TEST ID	DOCK LOCATION (S)	SIZE ID (INCHES) (4)	MAWP (PSI) (5)	OPERATING PRESSURE (PSI) (6)	TPRV (PSI) (7)	ACCESS
VAPOR CONTROL LINE	P603184	EAST	14, 18, 24	5	-0.8	(8)	ELEV
VAPOR CONTROL LINE	P603185	CENTER	14, 18, 24	5	-0.8	(8)	ELEV
VAPOR CONTROL LINE	P603186	WEST	14, 18, 24	5	-0.8	(8)	ELEV
VCS ENRICHMENT/SWEEP NAT GAS	P603187	EAST	1.5, 4	250	200	(8)	ELEV
VCS ENRICHMENT/SWEEP NAT GAS	P603188	CENTER	1.5, 4	250	200	(8)	ELEV
VCS ENRICHMENT/SWEEP NAT GAS	P603189	WEST	1.5, 4	250	200	(8)	ELEV
PHENOLIC CONDENSATE LINE	P603121	CENTER	2	125	100	(8)	ELEV
PHENOLIC WATER SUMP	P603113	CENTER	2	235	40	(8)	ELEV
PHENOL	P603149	CENTER	10	125	65	(8)	ELEV/INSUL
#1 SOL VM&P	P603111	WEST, CENTER, EAST	6, 8	125	35	275	ELEV
#4 SOL ODORLESS MIN SPT	P603108	WEST, CENTER, EAST	6,8	125	35	275	ELEV
#5 SOL AROMATIC 100	P603107	WEST, CENTER., EAST	6, 8	125	35	275	ELEV
TOL A	P603154	WEST, CENTER, EAST	6, 8	125	35	275	ELEV
SOL B	P603152	WEST, CENTER, EAST	8	125	35	250	ELEV
EHA	P603134	WEST, CENTER, EAST	8	125	65	[illegible]	[illegible]
MIBK D348	P603147	WEST, CENTER, EAST	8	125	60	150	ELEV
DMK F354	P603104	WEST, CENTER, EAST	12	125	65	150	ELEV
DMK F335	P603105	WEST, CENTER, EAST	8	125	60	150	ELEV
NBA F347/F349	P603133	WEST, CENTER, EAST	8	125	50	150	ELEV
BUNKERS M301	P603148	WEST, CENTER, EAST, BARGE, CRUDE	6, 8, 16	125	50	(8)	ELEV/INSUL
DIESEL M302	P603150	WEST, CENTER, EAST, BARGE, CRUDE	6, 8, 12	125	60	150	ELEV
IBA D354	P603162	WEST, CENTER, EAST	6, 8	125	60	150	ELEV
XYLENE F350	P603116	WEST, CENTER, EAST	6, 8	[illegible]	60	[illegible]	[illegible]
XYLENE F3[illegible]	B070549	WEST, CENTER, EAST	6, 8	125	55	150	ELEV
IPA F337	P603103	WEST, CENTER, EAST	8, 12	125	60	150	ELEV
IPA F353	P603138	WEST, CENTER, EAST	8	125	70	150	ELEV
CHEMICAL SUMP	P603169	WEST, CENTER, EAST, BARGE	2	125	60	(8)	ELEV
#2 CRUDE	P603151	WEST, CENTER, EAST	12	125	55	275	ELEV
UTILITY CHEMCIAL	P603119	WEST, CENTER, EAST	6	125	55	(8)	ELEV
UTILITY ALKY	P603118	WEST, CENTER, EAST	8	125	60	275	ELEV
CUMENE D342	P603172	BARGE.	6, 8	125	80	150	ELEV
CUMENE D342	P603135	WEST, CENTER, EAST.	8	125	80	150	ELEV
MTBE	B070551	WEST, CENTER, EAST, BARGE	18	125	45	180	ELEV
50% CAUSTIC D368/D382	P603136	CENTER, EAST, BARGE	6, 10	125	45	150	ELEV/INSUL
GO-1 INTERMEDIATES	P603141	WEST, CENTER, EAST, BARGE	10, 14	125	75	275	ELEV
MEK F351	P603120	WEST, CENTER, EAST,	8	125	60	150	ELEV
MEK F338	P603139	WEST, CENTER, EAST,	8	125	80	150	ELEV
3" CHEMICAL SLOP	P603124	WEST, CENTER, EAST,	3	125	45	(8)	ELEV
METHANOL	P603106	WEST, CENTER, EAST, BARGE	8	125	65	150	ELEV
WOOD RIVER INTERMEDIATES	P603142	WEST, CENTER, EAST,	8	125	75	275	ELEV
FINISHED ECH D-358	P603102	WEST, CENTER, EAST,	6, 8	125	75	150	ELEV
CRUDE ECH D340	P603112	WEST, CENTER	4, 8	125	65	150	ELEV
WAX	P603129	EAST	10	125	75	(8)	ELEV/INSUL
BALLAST	P603144	WEST, CENTER, EAST, CRUDE	18	125	40	(8)	ELEV
LIGHTERING LINE LUBES/SOLV	P603165	EAST, BARGE	6, 8	125	50	(8)	ELEV
SR RESIDUE	P603181	BARGE	6	125	35	275	ELEV
#2 AVIA GASO COMPONENTS	P603140	WEST, CENTER, EAST	8, 10	125	45	275	ELEV
KEROSENE	P603126	WEST, CENTER	12, 14	200	60	150	ELEV
SPENT CAUSTIC	P603180	BARGE	6	[illegible]	45	(8)	ELEV

U.S. Department of Transportation
United States Coast Guard

Commanding Officer
U. S. Coast Guard
MSO Houston

P. O. Box 446
Galena Park, TX 77547
PH: 713 671-5100

APR 2 1 1992
16460

From: Commanding Officer, Marine Safety Office Houston
To: Commandant (G-MEP-1)
Via: Commander, Eighth District (m)

Subj: EXXON COMPANY U.S.A., BAYTOWN, TX, PIPE SYSTEM TESTING

Ref: (a) COMDT (G-MEP) MSG 102116Z FEB 92

1. In accordance with reference (a), I am forwarding enclosure (1) for your consideration. Mr. Brian W. Cooper, Exxon Company U.S.A.'s Dockmaster, is requesting an alternative procedure for testing their marine transfer piping system in accordance with Title 33 CFR Part 156.170(c)(4).

2. Exxon Company's Baytown refinery will need two alternatives under current Coast Guard policy. The first would apply to their overall operation and is not clearly described in their April 8, 1992 letter. I have inspected the facility personally and observed a fire wall constructed along the facility's waterfront. All pipelines lead behind this fire wall, which acts as a containment system. The ground inland from the wall is sloped downward into the facility's waste water treatment system. I am confident that any spills occurring within the confines of the fire wall would be contained and not reach navigable waters. Secondly, I have reviewed Exxon's proposal for non-destructive testing of the #1 Dock piperack and the draft copy of the API 570 Piping Inspection Code published by the American Petroleum Institute. The API 570 code appears to be sound engineering and logically formatted. I recommend that Exxon Baytown's #1 Dock piperack be granted an alternative for non-destructive pipe testing done in accordance with API 570. I further recommend that the frequency of testing be conducted annually for three years to establish a pattern within the marine environment and that Exxon notify my office of any temporary repairs made to their piping systems. This alternative should be reviewed annually and subject to repeal if shown to be not as effective as static liquid testing.

R. J. PROSSER
Commander, U. S. Coast Guard
By direction

Encl: (1) Exxon Company, U.S.A. letter dated April 8, 1992

cc: Exxon Company, U.S.A.

ENCLOSURE (3)